Conf-921021C--1

DOE/MC/11076-93/C0080

DOE/MC/11076--93/C0080

DE93 002713

Bell Pole CROW Pilot Test Results and Evaluation

Authors:

Fahy, L.J.
Johnson, L.A. Jr.
Sola, D.V.,
Horn, S.G.,
Christofferson, J.L.

Contractor:

Western Research Institute
P.O. Box 3395
University Station
Laramie, Wyoming 82071-3395

Contract Number:

DE-FC21-86MC11076

Conference Title:

Colorado Hazardous Waste Management Society Annual Conference

Conference Location:

Denver, Colorado

Conference Dates:

October 1992

Received by OSTI

NOV 1 0 1992

MASTER

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

DISCLAIMER

Available to DOE and DOE contractors from the Office of Scientific and Technical Information, P.O. Box 62, Oak Ridge, TN 37831; prices available from (615)576-8401, FTS 626-8401.

Available to the public from the National Technical Information Service, U.S. Department of Commerce, 5285 Port Royal Rd., Springfield, VA 22161.

BELL POLE CROW PILOT TEST RESULTS AND EVALUATION

Fahy, L.J. and L.A. Johnson Jr., **Western Research Institute**, P.O. Box 3395, Laramie, WY 82071 and D.V. Sola, S.G. Horn, and J.L. Christofferson, **Conestoga-Rovers and Associates Limited**, 1801 Old Highway 8, Suite 114, St. Paul, MN 55112

INTRODUCTION

Beginning in 1990, efforts were initiated to implement an in situ remediation project to address the creosote and pentachlorophenol (PCP) contaminated surficial aquifer at the Bell Lumber and Pole Company (Bell Pole) Site. The remediation project involves the application of the Contained Recovery of Oily Wastes (CROW^{TM}) process which consists of hot-water injection to displace and recover the non-aqueous phase liquids (NAPL) (Johnson and Sudduth 1989).

Wood treating activities began in 1923 at the Bell Pole Site in New Brighton, Minnesota. Wood treating activities have included the use of creosote and PCP in a fuel oil carrier. Creosote was used as a wood preservative from 1923 to 1958. A 5 to 6% mixture of PCP in fuel oil was used as a wood preservative from 1952 to the present. Provalene 4-A, a non-sludging fuel-oil-type carrier for PCP, was used from 1952 until it was no longer commercially available in 1968. From 1968 to the present, a fuel-oil-type carrier P-9 has been used.

An Interim Response Action (IRA) work plan was prepared in 1990 by Conestoga-Rovers and Associates, Limited (CRA), and Western Research Institute (WRI). The IRA detailed how the CROW process would be implemented at the Bell Pole Site (CRA and WRI 1990). Based on the IRA and after the granting of variances by the Minnesota Pollution Control Agency (MPCA) and the Minnesota Department of Health (MDH), a two-well pilot test of the CROW process was conducted. The test consisted of injecting hot, potable water into the NAPL saturated area of the aquifer, producing groundwater (and NAPL) from an existing production well, PW1, and treating the produced water for sanitary sewer discharge.

The objectives of the pilot test were to:

1. compare predicted injection and production rates with actual field data;
2. demonstrate the ability to heat the aquifer to the 120°F to 140°F range;
3. demonstrate the ability to hydraulically control the injected water to prevent spreading contamination;
4. confirm treatment system effectiveness in reducing PCP and polynuclear aromatic hydrocarbons (PAHs) prior to sanitary sewer discharge; and
5. predict anticipated operating conditions for full-scale CROW application.

SITE CHARACTERIZATION

Characterization of the contaminated area at the Bell Pole Site has been ongoing for several years by CRA and other consultants. The two uppermost geologic formations identified beneath the Bell Pole Site include the New Brighton and Twin Cities formations (Stone 1966). For simplicity, the primary hydrogeologic units have been labeled Unit 1 and Unit 2.

Unit 1 is a 23-47 ft thick, surficial aquifer of the New Brighton Formation. The New Brighton Formation consists of uniform silty, fine to medium, gravel/sand. Unit 1 is recharged through precipitation and by percolation, with groundwater flowing primarily to the southwest and discharging to a county drainage ditch. The water table ranges from 10 to 20 ft below ground surface (BGS) and elevations range from 895 ft above mean sea level (AMSL) in the southwestern portion of the site to 903 ft AMSL in the northeastern corner.

Unit 2 is a till material of the Twin Cities Formation which creates an effective aquitard separating Unit 1 from lower aquifers. Unit 2 is approximately 96 ft thick at the site and is comprised of silty to sandy clay and silt. The hydraulic conductivity of Unit 2 is on the order of 1.0×10^{-7} cm/sec, based on laboratory testing. This low hydraulic conductivity and the thickness of Unit 2 makes it a competent aquitard.

In February 1990, 22 boreholes were drilled in the vicinity of the former process area to define the extent of NAPL contamination. An isopach map of the NAPL distribution is shown in Figure 1. The NAPL appears to form an elongated teardrop shape which extends northeast of the former process area. The maximum thickness is in the center of the zone and comprises the entire 20 to 25-ft thickness of the aquifer. NAPL diminishes to 1 to 2 ft in thickness along the perimeter of the contaminated zone.

WELL DRILLING AND COMPLETION PROCEDURES

One injection well, IW1, and four monitor wells, BP27-BP30, were drilled and installed for the pilot test (Figure 2). The newly installed injection and monitor wells were drilled using cable tool drilling techniques to the top of Unit 2. During drilling, soil samples were collected using the cable tool bailer and a split-spoon sampler. Samples were collected until the water table was identified, then soil samples were collected continuously to the top of Unit 2 and were used for stratigraphic, grain size, and NAPL saturation determinations. For the injection well, a 15-ft long sand screen was placed from Unit 2 to approximately 5 ft below the water table and 4-inch diameter carbon- steel casing was run to the surface. The sand screen was gravel packed and the casing was cemented in place.

Monitor wells were completed with a 2-inch I.D., 0.010 inch continuous slot stainless steel screen, 5 ft in length. Screens were welded to 2-inch diameter Schedule 40 carbon-steel casing and set on top of Unit 2 and gravel packed. The sand pack extended from the bottom of the boring to approximately 13 to 16 ft BGS. The sand screens were also gravel packed and the casing was cemented in place.

Immediately following the end of the pilot test, two soil borings, CT1 and CT2, were drilled adjacent to the injection well (see inset of Figure 2). These borings were drilled using 4 1/4-inch hollow-stem augers to the top of Unit 2. Soil samples were collected from surface to 15 ft BGS, then samples were collected continuously to the top of Unit 2.

AQUIFER MONITORING EQUIPMENT

Prior to installing pipe in monitor wells BP27, BP28 and BP29, thermocouples were affixed to the outside of the pipe at 5-ft intervals below the water table. Each well had four thermocouples positioned at approximately 18, 23, 28, and 33 ft BGS. Each of the thermocouples were connected to the data acquisition system which recorded the formation temperatures at predetermined time intervals. In addition, manual temperature monitoring was conducted at well locations using a digital thermometer.

Monitor well BP24, which had been completed earlier, had been constructed with four 1-inch diameter, plastic pipes. The plastic pipes had been set at different elevations, to collect piezometric data. Thermocouples were installed in three of the piezometer pipes at approximately 22, 32, and 37 ft BGS.

Pressure transducers were used in monitor wells BP24, BP27, BP28, and BP29 for water level measurements at predetermined time intervals. Each pressure transducer was set within 10 ft from the top of the water table and was sensitive to within 0.03 ft. All data were recorded by the data acquisition system.

An electric water level tape was also used at most monitor wells to observe the aquifer throughout the pilot test. NAPL accumulations in wells PW1, BP24, BP25, BP28, and BP29 tended to foul the accuracy of the electric water level tape and therefore an oil/water interface probe was utilized.

DESCRIPTION OF SURFACE EQUIPMENT

Potable water was used by a boiler unit that supplied steam to the attached heat exchanger to heat the injected water. The injected water entered the 12-inch multiple-pass heat exchanger at approximately 70 pounds per square inch (psi) and 55°F and was heated to approximately 200°F. The hot-water flow rate was throttled to approximately 5 gpm using a pressure relief valve, and injected down the casing into the aquifer at IW1.

Water and NAPL produced from PW1 flowed into a 40,000-gallon production tank located in a clay lined berm near PW1 (Figure 3). This tank served as a primary oil/water separator. The tank was heated during the test using steam from the boiler. Floating oil was removed from the tank using a floating oil skimmer and transferred to a 250-gallon fiberglass holding tank. From the holding tank, oil was pumped into a storage tank. The dense oil was allowed to accumulate in the bottom of the production tank until the test was completed.

From the production tank, water was pumped into a skid mounted, coalescing oil/water separation system. Light and dense oils were removed from the coalescing separator system and pumped into the oil storage tank. Water from the separator flowed to a microfiltration unit where PCP and fine oil droplets were treated. Water was then pumped through 0.2 micron filters, trapping fine oil droplets. The water then flowed through two activated carbon units where PCP and PAHs were removed. Treated water was then discharged to the sanitary sewer.

PILOT TEST DESCRIPTION

The pilot-test location was selected based on the NAPL isopach mapping and the location of the existing production well, PW1. The injection and production wells were located in the area that contains high NAPL accumulations.

The pilot test began on September 24, 1991. The first step of the test involved pumping the production well, PW1, at a rate of 5 gpm. Treatment of water began on September 26, day 3 of the test. On day 4, production was increased to 9 gpm. Hot-water injection was started on day 7 at 5.4 gpm. The initial injection temperature was 147°F. On day 9, the injection temperature was increased to 203°F. Injection was terminated on October 31, day 37 of the pilot test. Pumping continued at PW1 until day 41 when the test ended. Water treatment continued until day 45 and the treatment system was subsequently dismantled.

Over the entire test, the pumping rate of PW1 averaged 6.5 gpm. The hot-water injection rate averaged 4.5 gpm. The pumping rate was consistently higher than the injection rate throughout the test. The test operating conditions and results are summarized in Table 1.

Water levels and temperatures in the aquifer were monitored throughout the test. Wellhead injection and production temperatures and the downhole temperatures were continuously recorded for BP24, BP27, BP28, and BP29. Manual temperature readings were also taken daily.

PILOT TEST RESULTS

Flow rates and injection pressure were recorded by the data acquisition system. The pumping rate at PW1 was started at 5 gpm and stepped up to 9 gpm during the 7 days prior to injection start up. During the remainder of the test, PW1 averaged 6.5 gpm (Table 1). The production flow rate during the test is presented in Figure 4.

The injection rate was relatively constant during the test and averaged 4.5 gpm. Injection pressure increased during the test from 6 to 14 psig. The injection pressure and flow rate are presented in Figure 5.

Temperatures were measured at the injection and production wellheads and at the monitor well locations. The IW1 and PW1 temperature histories are shown in Figure 6. Only the three interior monitor wells, BP24, BP28, and BP29, and well PW1 showed a significant temperature response during the test. Typical formation temperature profiles are shown in Figures 7 and 8 for different times during the test for interior monitor wells BP24 and BP29, respectively.

Early temperature data indicated that the hot water might be having a tendency to override and travel predominantly across the top of the aquifer. However, as shown in Figures 7 and 8, the temperatures in the lower intervals increased until at the end of the 30-day injection period, the temperature profile at BP24 showed a very uniformly heated front. At the end of the test, more vertical temperature variation occurred at BP29 than at BP24, but the highest temperatures were more toward the center of the zone indicating that the hot water was not traveling across the top of the zone but was heating the entire interval uniformly.

In all cases, a temperature equal to or greater than the targeted 140°F was achieved in the three interior monitor wells. Downhole temperature measurements at well PW1 also indicated that 150°F fluids had reached PW1 prior to the conclusion of the hot-water injection phase (Figure 6).

While the hot-water front was growing horizontally from the injection well toward PW1, it also expanded vertically. Injection at IW1 occurred into a 15-ft interval between 20 and 35 ft BGS and about 5 ft below the top of the water table. However, at wells BP28 and BP29, temperatures of approximately 150°F were achieved at the top of the water table. Similarly, at BP24 the hot-water front extended from the top of the water table to Unit 2, about a 25-ft interval. By the end of the test, the entire thickness of the aquifer had reached the targeted temperature.

To estimate the areal extent of the hot-water injection front from field data, a flowstream pattern was developed (Figure 9) from groundwater levels measured on day 32. When the isopotential lines and streamlines are known, the fluid interface position can be estimated until the hot water breaks through at the production well (Craft and Hawkins 1959). Using this technique, the shape of the front and the area affected by the hot water were estimated. Once the areal extent of the hot water was determined, time of breakthrough and the arrival time of the hot-water front at the production well was calculated. The areal sweep calculation results are presented in Table 1.

NAPL arrival at PW1 was noted by increased levels of floating oil at the top of the water table, only 6 days before breakthrough of the hot-water front. Due to time and surface equipment limitations, the maximum sustained production from PW1 was about 9 gpm. Late in the test, this rate had to be lowered to between 6 and 7 gpm. It became obvious after breakthrough that the floating oil was collecting on top of the water column in PW1 and was not being removed from the wellbore at the lower pumping rates.

After the test was concluded, two boreholes, CT1 and CT2, were drilled. The borehole locations were chosen to represent portions of the aquifer that received two different amounts of hot-water flushing. CT1 represents the aquifer out to approximately 4 ft from IW1 and CT2 represents the aquifer out to approximately 10 ft from IW1. The samples taken from the two boreholes were extracted to determine residual NAPL saturations. The residual NAPL saturations determined from the two boreholes were compared to initial conditions obtained from the core taken from the injection well, IW1 (Figure 10). The comparison assumed that before the test, the NAPL saturation profile at IW1 represented the entire 10-ft radius that included CT1 and CT2. Visual inspection of the core material from BP28 and BP29 and soil samplings collected above the water table all support the assumption of a uniform saturation profile between IW1 and CT2.

The CT1 and CT2 NAPL saturation profiles represent residual NAPL saturation at different distances from IW1 and thus for different pore volumes of water injected. To determine the residual NAPL saturation after flushing, the average values from intervals in CT1 and CT2 that corresponded to the 9-ft vertical zone containing the high NAPL saturation in IW1 were used. This interval was chosen because it had a consistently high initial NAPL saturation. This interval also had good contact with the injected hot water. The entire 21-ft interval did not have as uniform a saturation profile, making comparison difficult.

From the areal sweep flowstream plot (Figure 9) it can be assumed that radial flow occurred around the injection well out to CT2. As the volume of the reservoir that was swept increased, the total number of pore volumes injected decreased for a given injection volume. Consequently, by assuming radial flow, the number of pore volumes of flushing at the two boreholes can be estimated. Once the number of pore volumes of injected hot water has been determined for a given volume of the reservoir, the residual NAPL saturation as a function of pore volumes injected can be estimated.

A total of 193,000 gallons of hot water were injected during the test. Assuming radial flow, an equivalent of 16 pore volumes of water was injected 10 ft from IW1 (the location of CT2). At 4 ft from IW1 (the approximate location of CT1) an equivalent of 60 pore volumes were injected. These calculations were based on a porosity of 30% and 12.5% of the pore space reduced by residual (i.e. immobile) NAPL saturation.

From the NAPL saturation data determined for the core material from IW1, CT1, and CT2, the NAPL saturation as a function of pore volumes injected was developed (Figure 11). The displacement efficiency was also estimated and plotted, based on the initial NAPL saturation in IW1 for the 9-ft interval. The actual NAPL saturation in the 2-ft interval (the highest NAPL saturation) was just slightly higher than the average residual

NAPL saturation for the 9-ft interval after 16 pore volumes of water had been injected. The displacement efficiency for the 2-ft interval was also very close to that calculated for the 9-ft interval.

There was little improvement in oil displacement between the samples from CT1 (60 pore volumes flushed) and CT2 (16 pore volumes flushed). A residual NAPL saturation of 12.5% (on a pore volume basis) appears theoretically possible with 60 pore volumes flushed. From Figure 11 it can be seen that approximately 70% of the NAPL had been displaced after 20 pore volumes of injected hot water. It can be seen that after the first 20 pore volumes of water injected, the process efficiency declines drastically, consequently, the first 20 pore volumes of hot-water injection displaces the majority of the mobile NAPL. Additional pore volumes of water injected will displace increasingly smaller amounts of NAPL.

Two samples were chosen from the soil samples for PCP analysis. One sample was taken from the IW1 core at approximately 28 ft, the area of highest NAPL saturation and represents pretest conditions. A corresponding sample was taken from the CT1 borehole, at the same depth, to represent post-test conditions. Before hot-water injection, the PCP concentration was 2,100 mg/Kg. After hot-water injection, the PCP concentration was reduced to approximately 3.6 mg/Kg, greater than a 500 fold decrease in concentration.

TREATMENT SYSTEM PERFORMANCE ASSESSMENT

Treatment of produced water began on September 27, 1991, and continued through November 7, 1991. Approximately 390,000 gallons of water were effectively treated and discharged to the sanitary sewer during the test. Oil/water separation was accomplished by primary settling, skimming, and coalescing separation. Water samples were collected at various points along the treatment train (Figure 3).

It was observed that water produced from PW1 was a turbid light brown color with black streaks. It was assumed that the light brown phase indicated emulsified oil and the black streaks were evidence of free phase dense oil. Oil and grease concentrations from PW1 varied between 430 and 6300 mg/L (Table 2). A heterogeneous mixture of emulsified and non-emulsified oil could account for the variability in oil and grease concentrations. An average oil and grease concentration of 2,400 mg/L was calculated and correlates well with the amount of oil produced during the test (approximately 2,000 gallons). The PCP concentrations averaged 240 mg/L and total PAH's ranged from 38.3 to 1,390 mg/L. The most prevalent PAHs include 2-methylnaphthalene, acenaphthalene, dibenzofuran, naphthalene, and phenanthrene.

Oil and grease concentrations were reduced significantly through the oil/water separation equipment with average concentrations of 550 and 220 mg/L leaving the production tank and coalescing separation system, respectively. Water exiting the initial production tank was a turbid, light brown color with no visible black streaks indicating that the production tank was effective in removing the dense oil. Water leaving the coalescing separator was clear with a slight oil sheen. A graphical representation of average oil and grease concentrations at each step of the treatment system is presented in Figure 12. From this graph, it can be seen that a 90% reduction in oil and grease was accomplished through the oil/water separation equipment. The two samples collected after the coalescing separation system show PCP concentrations ranging from 33 to 64 mg/L which generally correlates with the reduction of oil during oil/water separation.

The microfiltration unit further reduced oil and grease concentrations to an average of 57 mg/L in three sampling events. After leaving the microfiltration unit, the process water flowed through the two activated carbon units that polished the water for PCP and PAHs to acceptable levels for sanitary sewer discharge. Samples collected from the effluent prior to sanitary sewer discharge show that carbon polishing was effective in reducing PCP to well below the discharge criteria of 2 mg/L. The treatment of PAHs to nondetectable concentrations was also accomplished by the activated carbon units.

CONCLUSIONS AND RECOMMENDATIONS

Based on the results from the pilot test the following conclusions can be made:

1. The pilot test provided sufficient hydraulic information to design the full-scale CROW remediation system. The pumping test portion of the pilot test indicated uniform aquifer properties. The entire thickness of the aquifer reached the target temperature range and containment of the injected hot water was achieved.
2. Pretest injection and production rate predictions were achieved.

3. The post test soil boring data indicated hot-water injection displaced greater than 80% of the NAPL near the injection well. The data indicates that a NAPL saturation of approximately 19% (pore volume basis) and a 500 fold decrease in PCP concentration can be achieved with 20 pore volumes of flushing.
4. The treatment system used during the pilot test was effective in reducing PCP and PAH compounds to concentrations acceptable for sanitary sewer discharge.
5. The microbial assay of the post test samples found an encouraging increase in microbial population compared to earlier data collected before the pilot test.

REFERENCES

Conestoga-Rovers and Associates Limited and Western Research Institute, August 1990, Interim Response Action Work Plan Bell Lumber and Pole Company Site, New Brighton, MN, Unpublished Report, 40 p.

Craft, B.C., and M.F. Hawkins Jr. 1959, Applied Petroleum Engineering, Prentice-Hall Inc., Englewood Cliffs, NJ, p. 412-413.

Johnson, L.A., and B.C. Sudduth, July 18, 1989, United States Patent No. 4,848,460, Contained Recovery of Oily Waste, Western Research Institute, Laramie, WY, 12 p.

Stone, J.E., 1966, Surficial Geology of the New Brighton Quadrangle, Minnesota, University of Minnesota Press, Minneapolis, MN, 39 p.

Table 1. Pilot Test Operating Conditions and Results

Total Hot-Water Injection Time	30 days
Average Hot-Water Injection Rate	4.5 gpm
Steady-State Hot-Water Injection Wellhead Temperature	200°F
Total Water Injected	193,000 gallons
Total Water and NAPL Production Time	41 days
Average Fluid Production Rate During Hot-Water Injection Phase	6.5 gpm
First Pumping Test Production Rate	5.0 gpm
Second Pumping Test Production Rate	9.0 gpm
Total Fluids Produced	390,000 gallons
Total NAPL Production	2000 gallons
Areal Extent of Injected Water	3285 ft^2
Time to NAPL Production Response From Start Of Injection	14 days
Time to Breakthrough from Start of Hot-Water Injection	20 days
Average Hot-Water Injection Front Velocity, ft/day	2.5 ft/day

Table 2. Summary of Organic Analytical Data

Location	PW1				After Production Tank	After Oil/ Water Separation Unit				After Microfiltration Unit				Between Carbon Units			Effluent	
Step	1				1.5	2				3				4			5	
Date	O&G	PCP	PAH	TOC	O&G	O&G	PCP	PAH	TOC	O&G	PCP	PAH	TOC	PCP	PAH	TOC	PCP	PAH
09/27/91	2000	<200	1390	220		140	64	12.6	47	17	<0.050	2.61	690	<0.050	ND	430	<0.050	ND
10/04/91	905			160										8.8	1.74	470		
10/08/91	6,300																	
10/11/91	810	300	38.3	220		130			110	110			790	0.14	ND	550	<0.050	ND
10/15/91	3,300																	
10/18/91	430			220										<0.050	0.108	140		
10/23/91	2,000																	
10/25/91					522	228												
10/29/91	4,200				570	390												
10/31/91	1,700	190	141.0	320	550	230	33.0	14.94	60	43	14.0	1.06	48				0.95J	ND

NOTES:
O&G--Oil and Grease
PCP--Pentachlorophenol
PAH--Total Polynuclear Aromatic Hydrocarbons
TOC--Total Organic Carbon
ND--Non Detectable, below detectable limits
J--Duplicate analysis reported 0.19 ug/l.
Blanks indicate that anlaysis was not performed
Concentrations reported in mg/l.

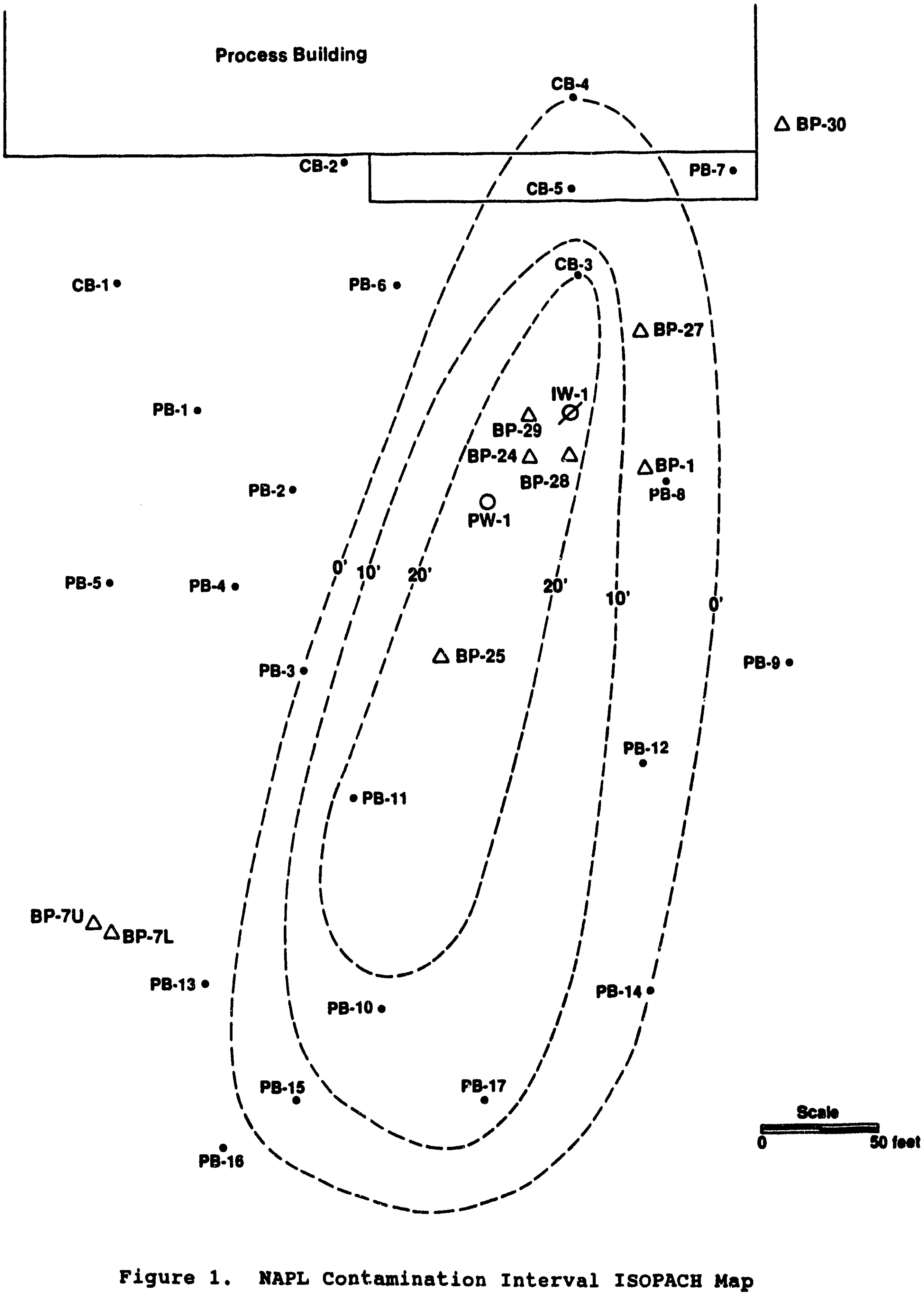

Figure 1. NAPL Contamination Interval ISOPACH Map

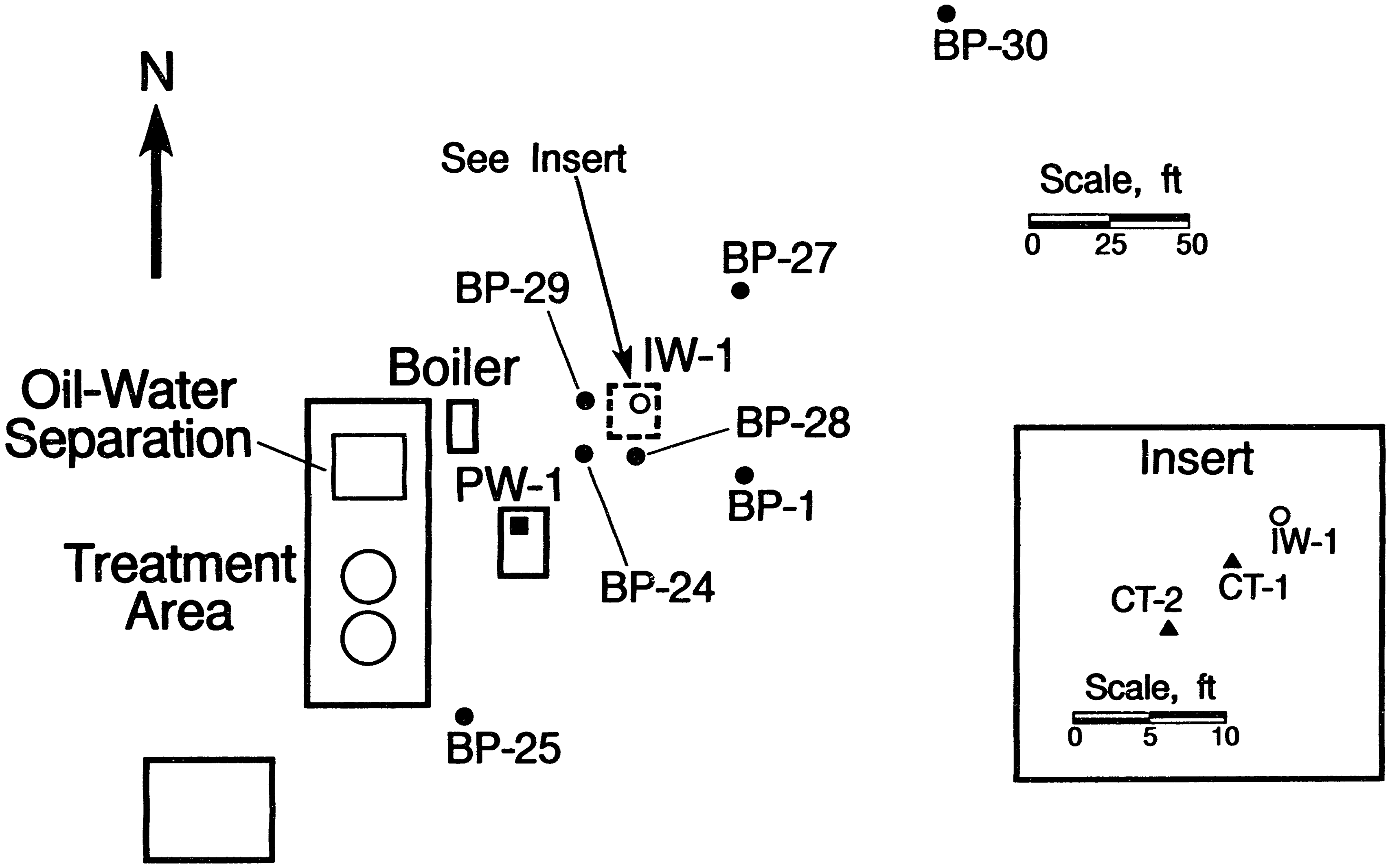

Figure 2. Pilot Test Location Map

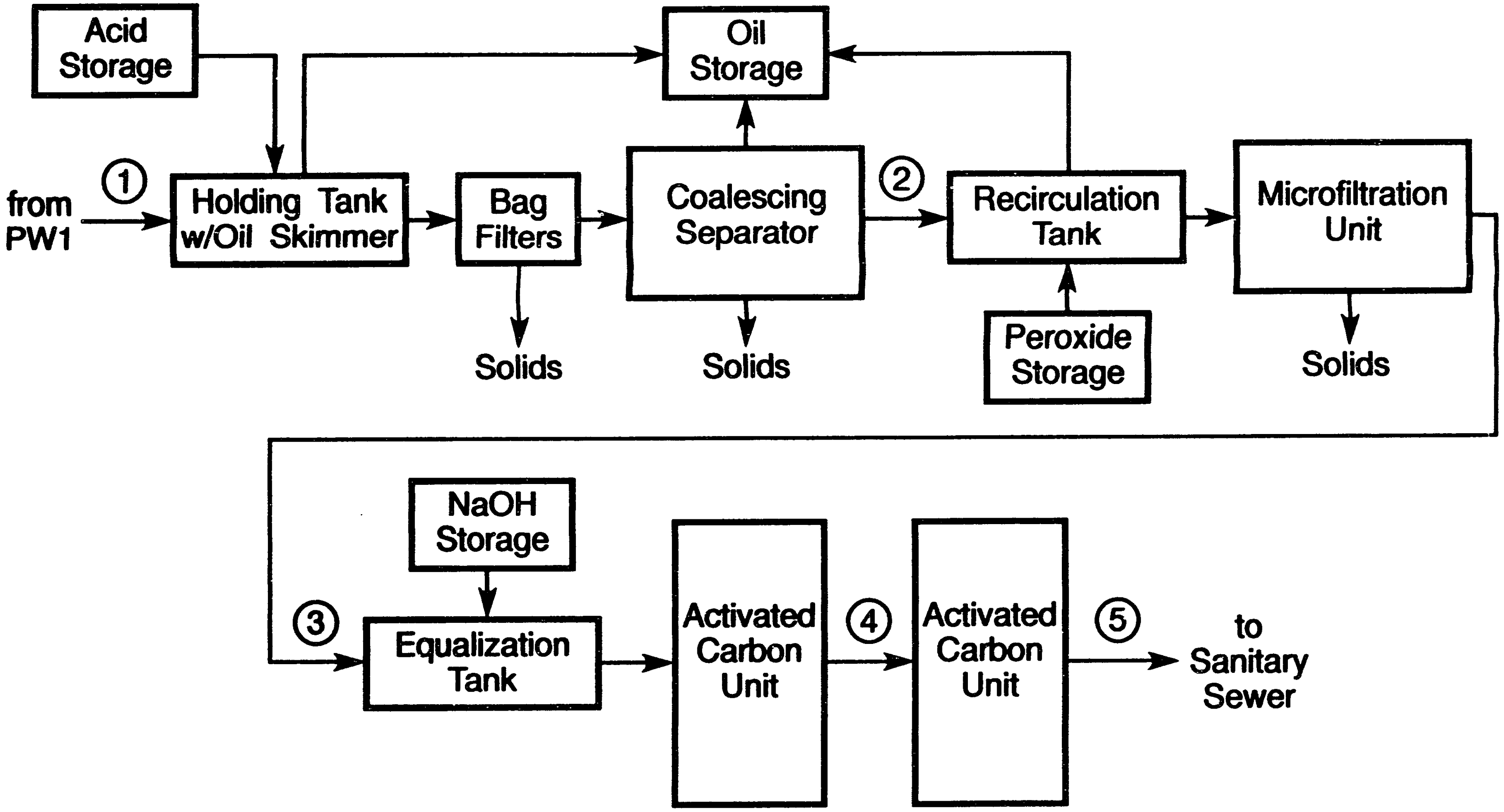

Figure 3. Pilot Test Treatment System Flow Diagram

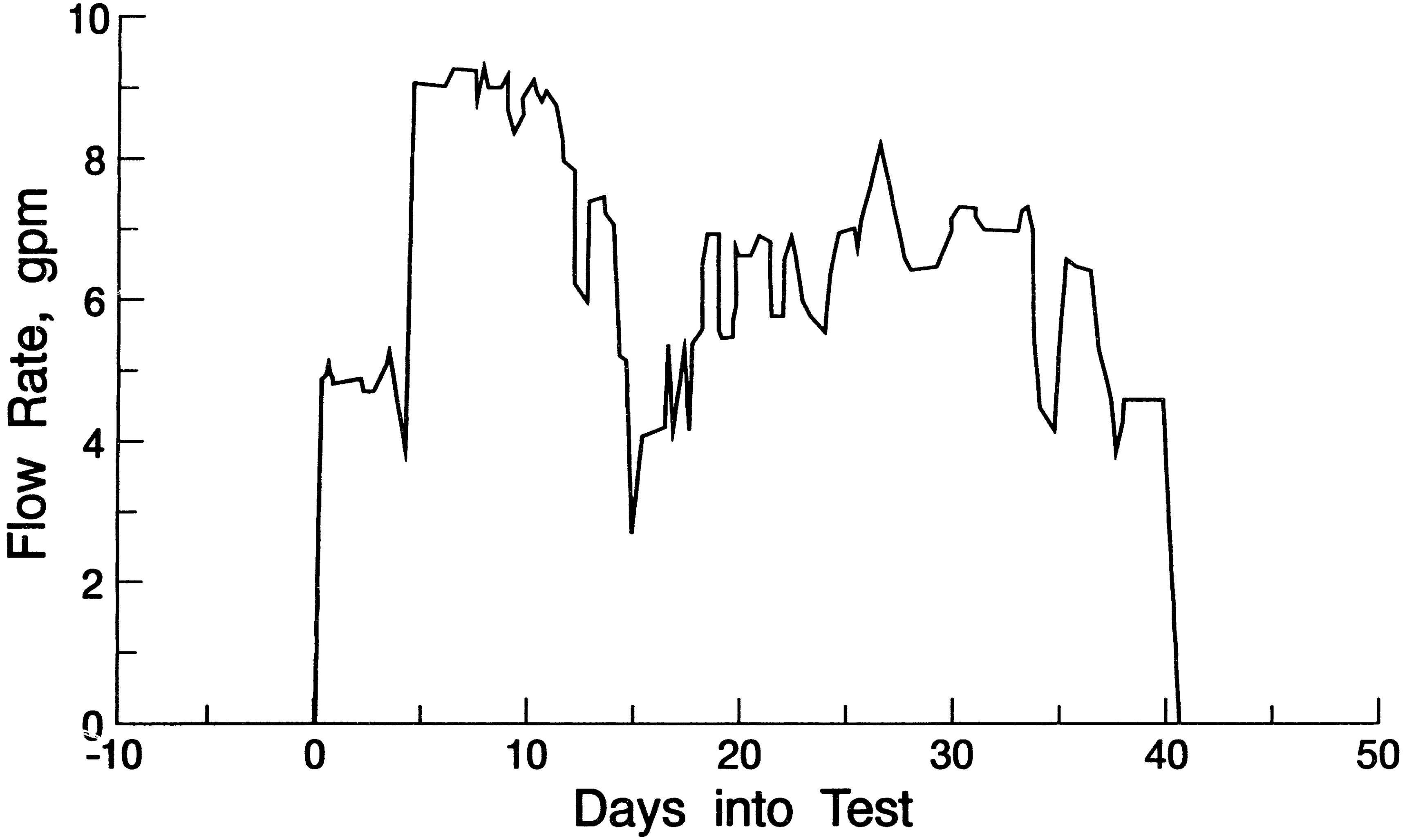

Figure 4. PW1 Production Flow Rate

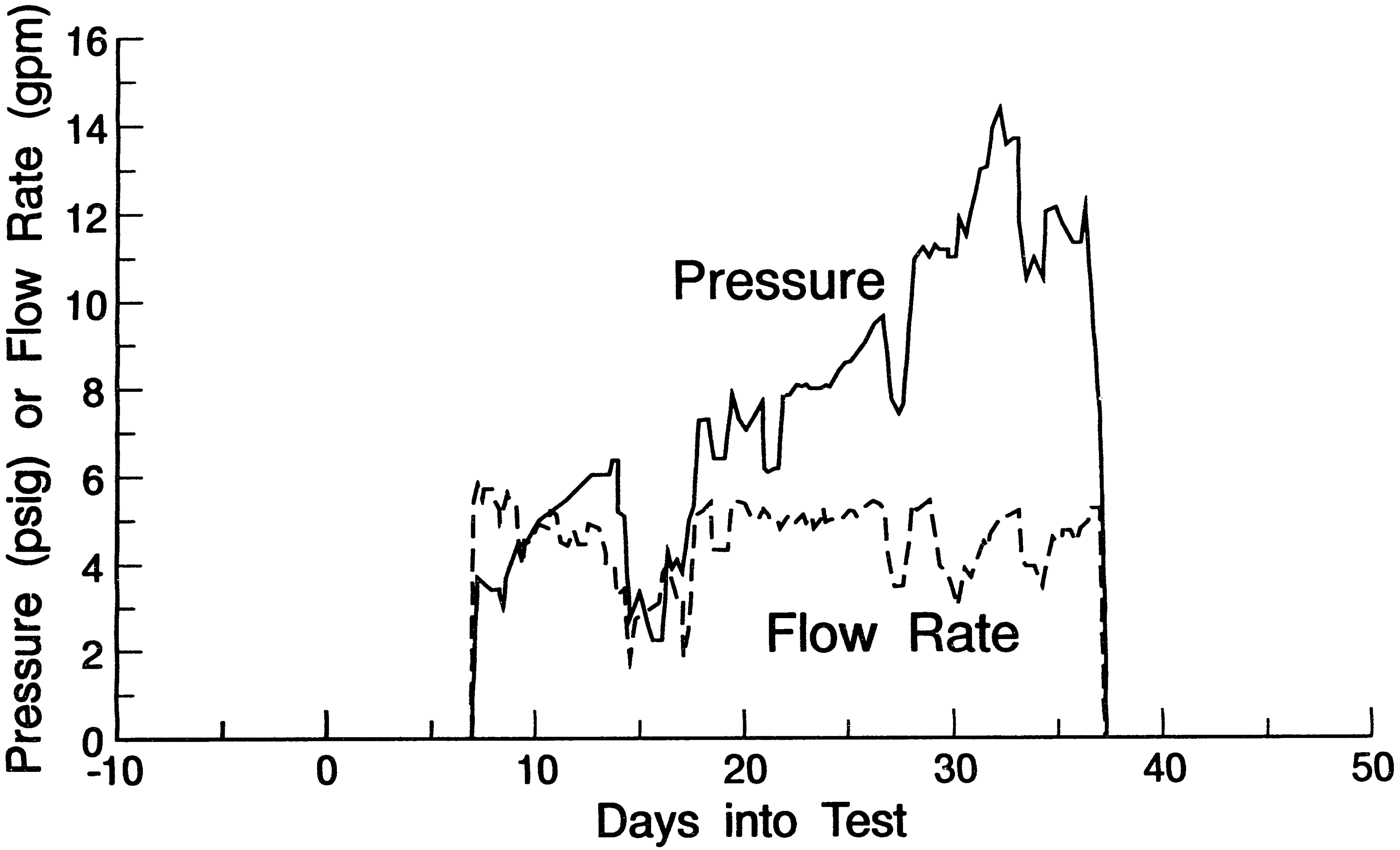

Figure 5. IW1 Injection Pressure and Flow Rate

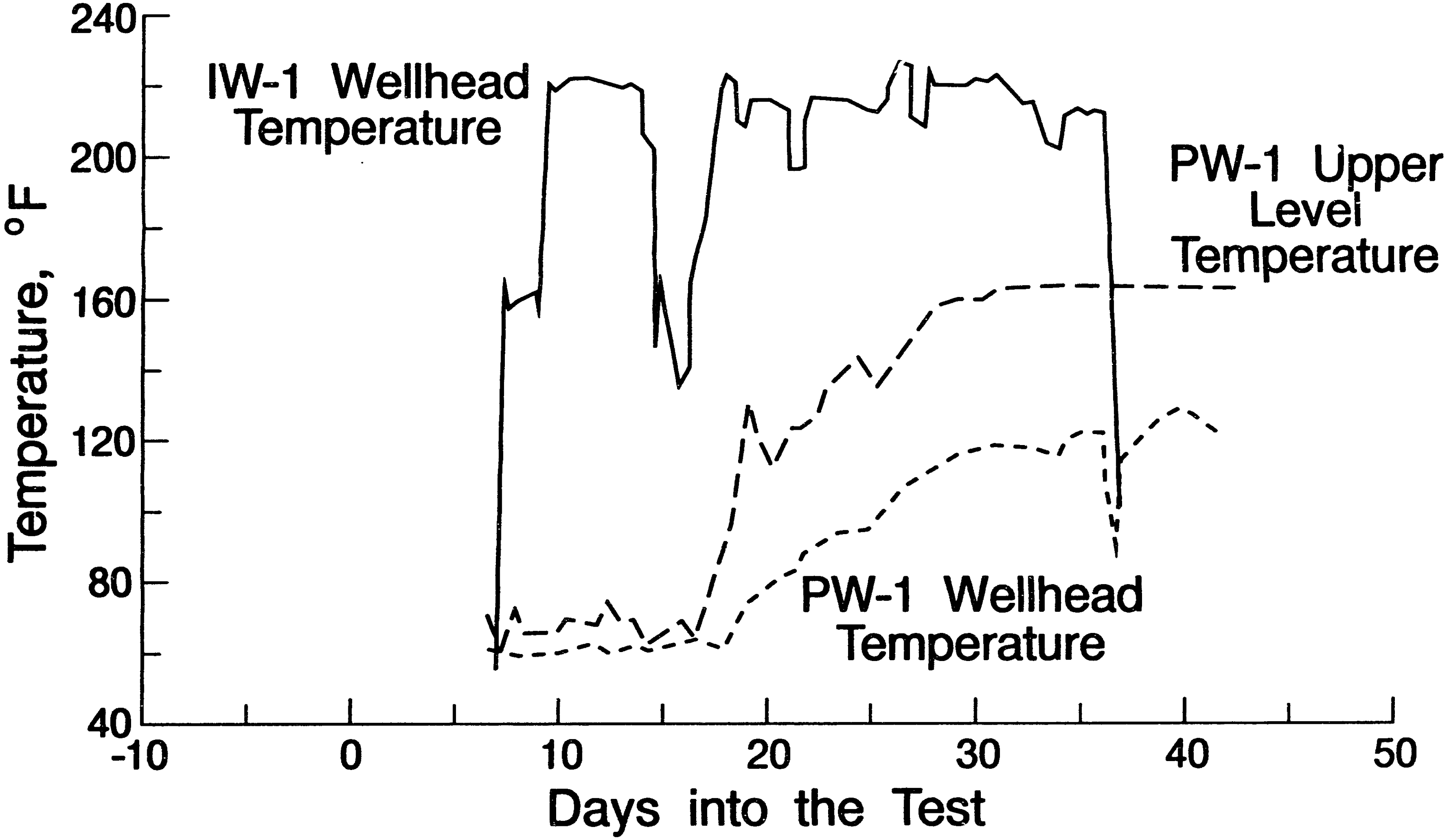

Figure 6. Injection and Production Well Temperatures

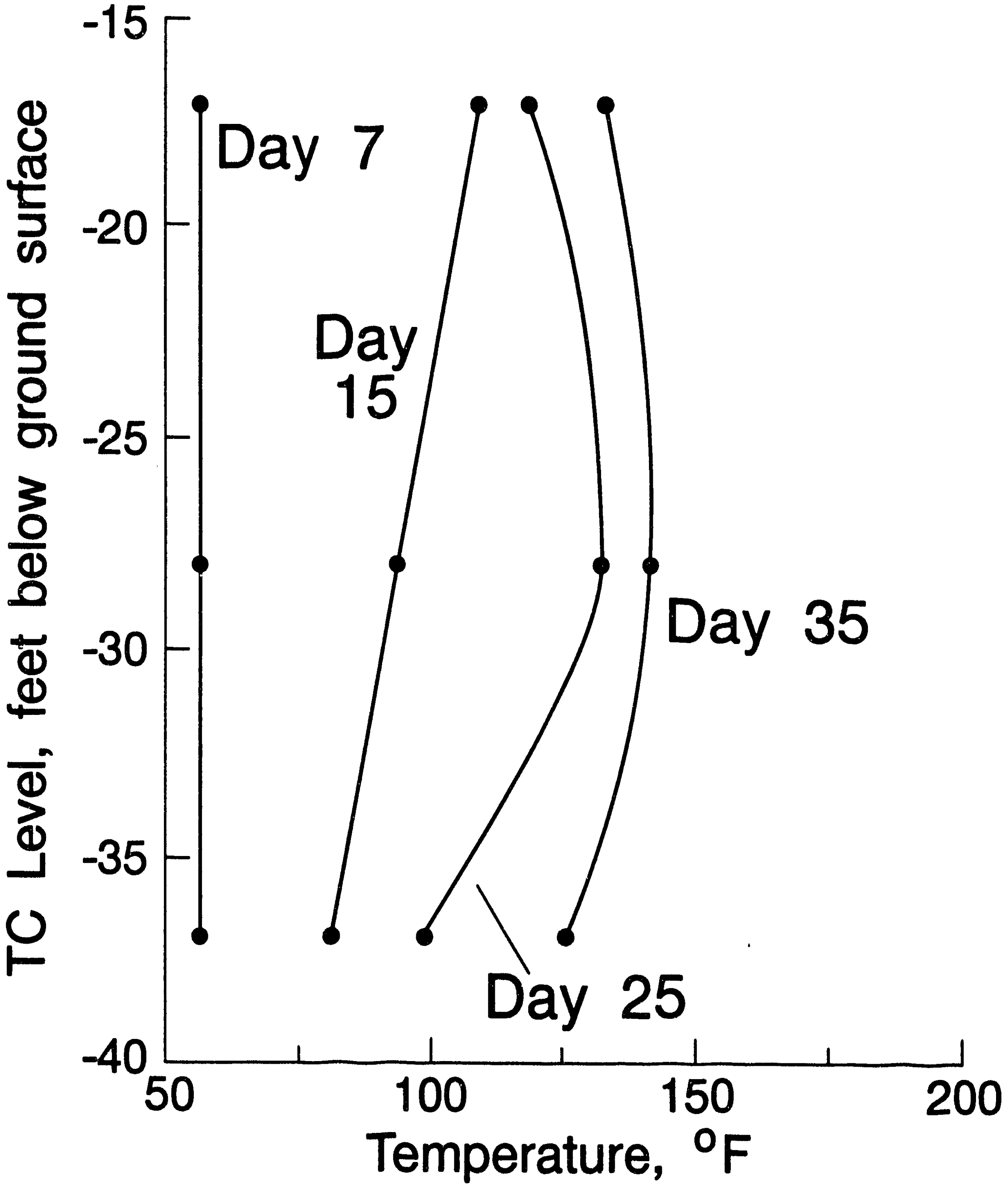

Figure 7. Temperature Profile for BP24

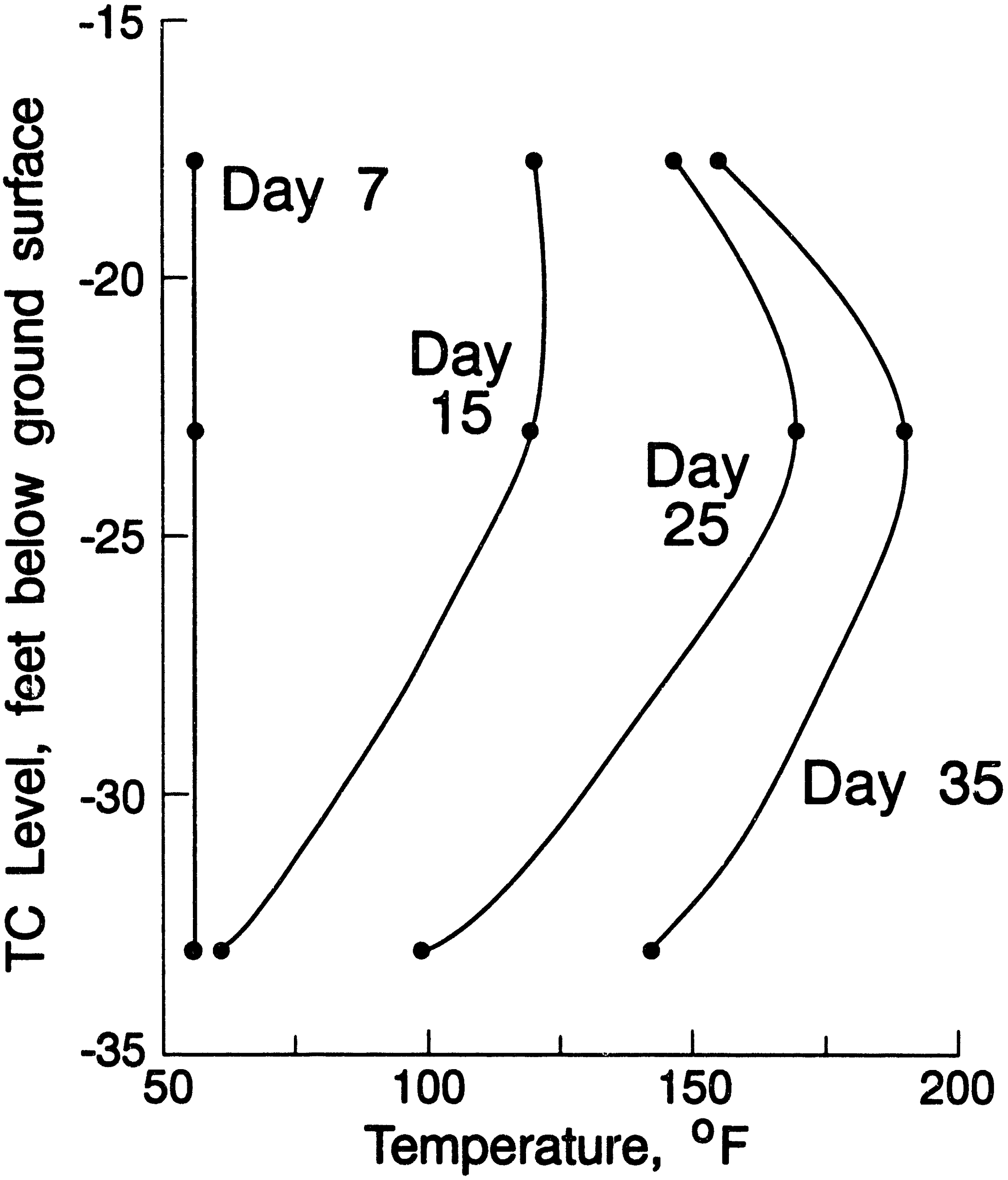

Figure 8. Temperature Profile for BP29

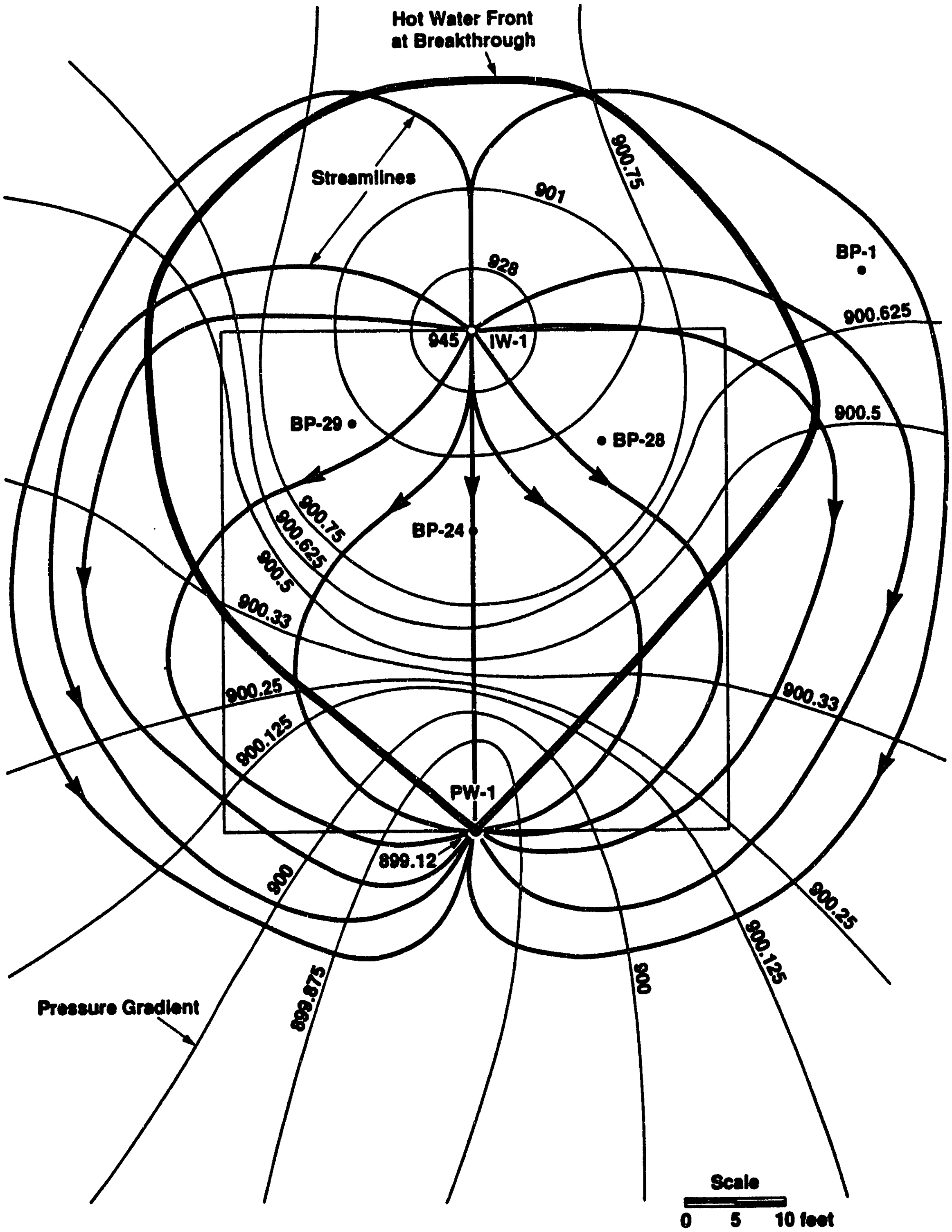

Figure 9. Pilot Test Exterior Well Flow Stream Patterns

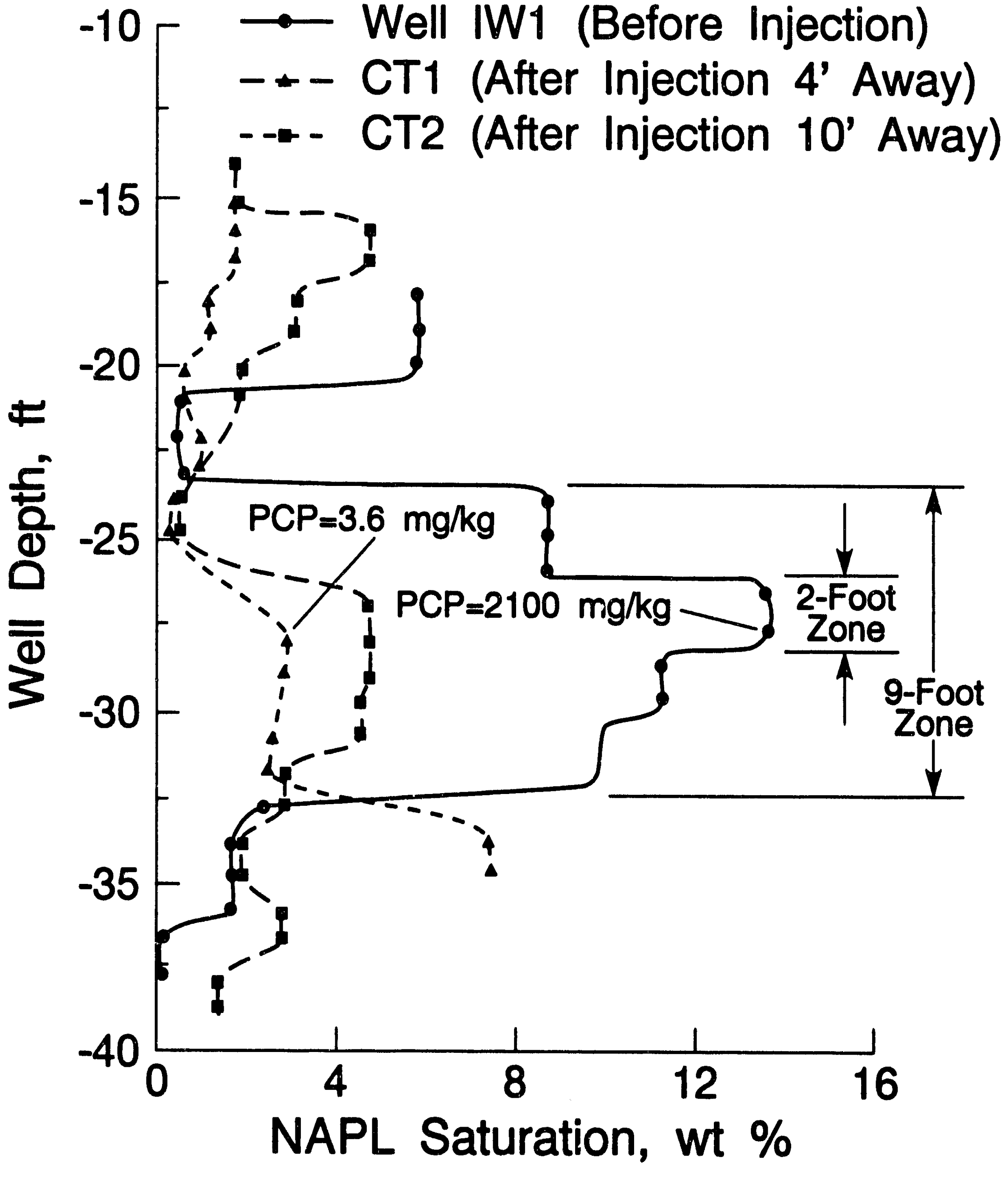

Figure 10. Pilot Test NAPL Saturation Profiles

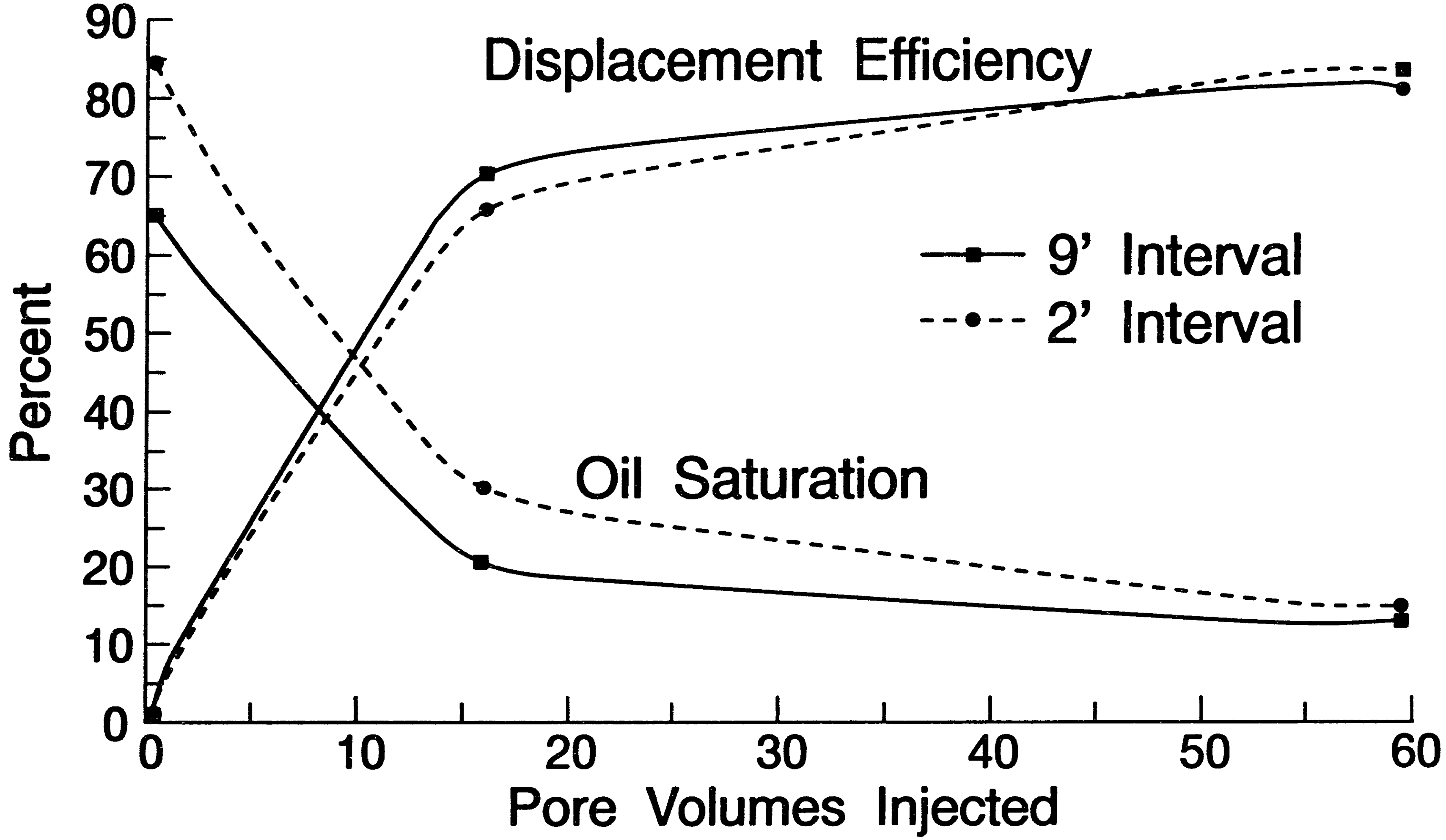

Figure 11. Pilot Test Displacement Efficiency

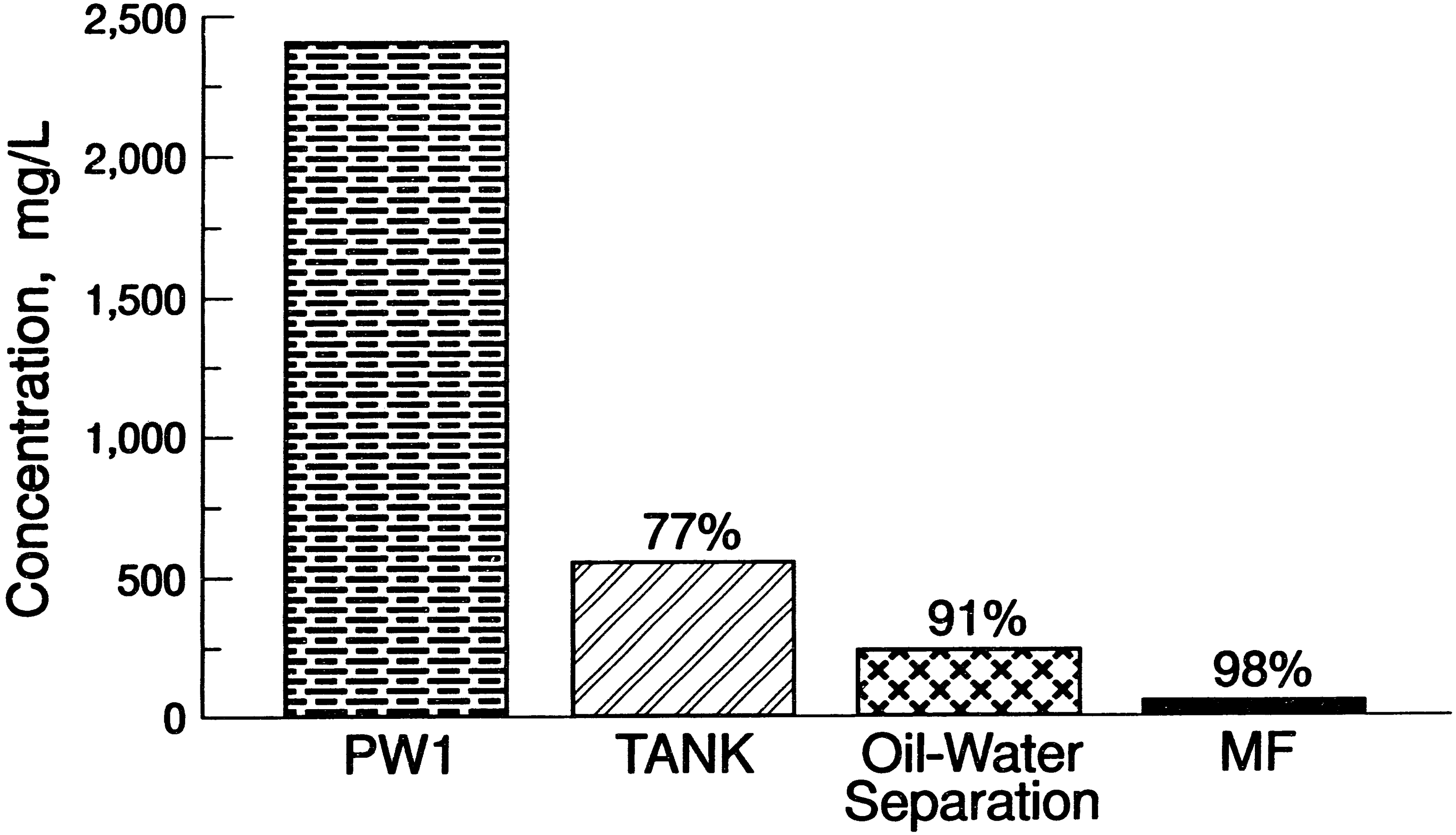

Figure 12. Oil and Grease Treatment Steps

END

DATE FILMED

1 / 27 / 93